STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF A FUEL COST ADJUSTMENT TO BE APPLICABLE DURING THE BILLING MONTHS OF MAY, JUNE AND JULY 2012, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 43969 AND FOR APPROVAL OF RATEMAKING TREATMENT FOR THE COST OF WIND POWER PURCHASES PURSUANT TO CAUSE NO. 43393.	**CAUSE NO. 38706 FAC 94** **APPROVED:** APR 25 2012

ORDER OF THE COMMISSION

Presiding Officers:
Kari A.E. Bennett, Commissioner
Angela Rapp Weber, Administrative Law Judge

On February 2, 2012, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") filed its Petition for Commission approval of a fuel cost adjustment to be applicable for bills rendered by Petitioner during the billing months of May, June, and July 2012. Petitioner also prefiled its direct testimony and exhibits in support of its Petition on February 2, 2012. NIPSCO Industrial Group ("Industrial Group") filed its Petition to Intervene on February 6, 2012, which was granted by the Presiding Officers in a Docket Entry dated February 20, 2012. To address a clerical error in the forecast for "Intersystem Sales through MISO" used to calculate the proposed factors discovered during the audit process, NIPSCO filed an Amended Verified Petition and revised direct testimony and exhibits on February 28, 2012. On March 8, 2012 the Indiana Office of Utility Consumer Counselor ("OUCC") filed its report in this Cause along with the Direct Testimony of Gregory T. Guerrettaz and Michael D. Eckert.

Pursuant to public notice given and published as required by law, a public hearing in this Cause was held on April 11, 2012 at 10:00 a.m. in Room 222 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana. At the hearing Petitioner, the OUCC, and the Industrial Group appeared by counsel. Petitioner and OUCC offered their respective evidence, which was admitted into the record without objection. The Industrial Group offered NIPSCO's response to an informal data request from the Industrial Group, which was also admitted into evidence without objection. No other party or members of the general public appeared.

Based upon the applicable law and the evidence of record, the Commission now finds:

1. **Commission Jurisdiction and Notice.** Proper notice of the hearing in this Cause was given as required by law. Petitioner is a public utility corporation incorporated under the laws of the State of Indiana, operating electric utility properties in northern Indiana. Petitioner is subject to the jurisdiction of this Commission as provided in the Public Service Commission Act, as amended, Indiana Code ch. 8-1-2. The Commission has jurisdiction over NIPSCO and the subject matter of this Cause.

2. **Petitioner's Characteristics.** Petitioner has its principal office at 801 East 86th Avenue, Merrillville, Indiana. Petitioner is engaged in rendering electric public utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery, and furnishing of such service to the public.

3. **Available Data on Actual Fuel Costs.** The Petitioner's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity in Petitioner's last base rate case Order approved December 21, 2011 in Cause No. 43969 ("43969 Order") was $0.028729 per kWh (Petitioner's Exhibit B, Revised Schedule 1, Ln. 30). Petitioner's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity for the months of October, November, and December 2011 averaged $0.029310 per kWh (Petitioner's Exhibit B, Schedule 5, p. 4, Ln. 28).

4. **Requested Fuel Cost Charge.** Petitioner seeks to change its fuel cost adjustment charge from the current charge of $0.004919 per kWh (Petitioner's Revised Exhibit 1-C, Ln. 8) to a credit of $0.000840 per kWh (Petitioner's Exhibit B, Revised Schedule 1, p. 1, Ln. 32) for all applicable bills rendered in May, June, and July 2012 billing months. The requested fuel cost adjustment includes a variance of $7,619,866 (Petitioner's Exhibit B, Revised Schedule 1, Ln. 26d) that was over-collected during October, November, and December 2011. Petitioner's estimated monthly average cost of fuel to be recovered in this proceeding for the period April, May, and June 2012 is $40,350,219 (Petitioner's Exhibit B, Revised Schedule 1, Ln. 24), and its estimated monthly average sales for that period are 1,356,380 MWh (Petitioner's Exhibit B, Revised Schedule 1, Ln. 11).

Petitioner also seeks to change its fuel cost adjustment for two existing customers billed under Rate Code 647. These customers are billed pursuant to contracts approved by the Commission that contain a different base fuel cost and require a special calculation until their expiration (Petitioner's Exhibit A). The charge would change from the current charge of $0.011188 per kWh to $0.005429 per kWh (Petitioner's Exhibit B, Revised Schedule 1, p. 2 of 2, Ln. 4) for all bills rendered in May, June, and July 2012 billing months.

5. **Statutory Requirements.** Indiana Code § 8-1-2-42(d) states that the Commission shall grant a fuel cost adjustment charge if it finds that:

> (1) The electric utility has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible;
>
> (2) The actual increases in fuel cost through the latest month for which actual fuel costs are available since the last order of the Commission approving basic rates and charges of the electric utility have not been offset by actual decreases in other operating expenses;
>
> (3) The fuel adjustment charge applied for will not result in the electric utility earning a return in excess of the return authorized by the Commission in the last proceeding in which the basic rates and charges of the electric utility were approved. However, subject to Ind. Code § 8-1-2-42.3, if the fuel charge applied for will result in the electric utility earning a return in excess

of the return authorized by the Commission in the last proceeding in which basic rates and charges of the electric utility were approved, the fuel charge applied for will be reduced to the point where no such excess of return will be earned.

(4) The utility's estimates of its prospective fuel costs for each such three (3) calendar months are reasonable after taking into considerations: (A) the actual fuel costs experienced by the utility during the latest three (3) calendar months for which actual fuel costs are available; and (B) the estimated fuel costs for the same latest three (3) calendar months for which actual fuel costs are available.

6. <u>Fuel Costs and Operating Expenses</u>. Petitioner's Exhibit 2-A shows that fuel costs for the twelve months ending December 31, 2011 were $71,636,521 (Petitioner's Exhibit 2-A, p. 1, Ln. 15) above the levels approved in the 43969 Order, the last proceeding in which Petitioner's basic rates and charges for electric service were approved. Petitioner's Exhibit 2-A also shows that the total operating expenses excluding fuel for the twelve months ending December 31, 2011 were $8,230,500 (Petitioner's Exhibit 2-A, p. 1, Ln. 17) above the levels approved in the 43969 Order. The Commission finds that Petitioner's actual increase in fuel costs for the twelve months ending December 31, 2011 have not been offset by actual decreases in other operating expenses.

7. <u>Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost</u>. Petitioner's witness Mr. Strnatka testified that NIPSCO made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. He testified that Petitioner's primary fuel for generation of electric energy is coal (83.36% for the three months ended December 31, 2011).

With respect to NIPSCO's coal procurement process, Mr. Strnatka testified that NIPSCO considers several factors in purchasing coal, including the delivered price, the coal quality that is best suited for a particular generating unit, the sulfur content, and the economic and technical suitability of certain low cost fuels to be blended at NIPSCO's generating units to maintain the lowest, reasonably possible "as-burned" fuel cost. Mr. Strnatka testified that NIPSCO also considers the availability, reliability, and diversity of particular coal suppliers and coal transporters in its fuel procurement practices. He stated that effective January 1, 2012, NIPSCO has four long-term contracts with three coal producers and is currently negotiating term contracts with two additional coal producers which would be effective April 1, 2012. He stated that NIPSCO would meet any remaining coal requirements through spot purchases. Mr. Strnatka explained that NIPSCO competitively bids all coal purchased under a long-term agreement. He stated NIPSCO prepares a preliminary evaluation sheet incorporating all of the bidder information such as mine origin, Btu, sulfur, ash, available tons per year, and price on both a per ton and $ per million Btu basis. He testified that the final evaluation sheet, in addition to the cost of coal, includes the transportation cost for each of the proposals and any adjustments required to place all bids on an equivalent basis. Mr. Strnatka stated that NIPSCO negotiates price and commercial terms and conditions with the low evaluated bidder(s).

Mr. Strnatka testified that due to volatility in the coal markets, producers and customers are reluctant to execute fixed price long term contracts without some type of market price adjustment mechanism and that maintaining a market price balance is beneficial to both parties.

He explained that two of NIPSCO's long-term contracts have firm prices that increase each year as set out in the contract. One long-term contract has prices that are adjusted annually for the succeeding year based on the average weekly indexed prices of that particular coal in the previous year, and one long-term contract has an annual market price reopener that will determine the contract coal price for the succeeding year of the contract.

Mr. Strnatka testified that before NIPSCO agrees to a coal price increase based on contract provisions, NIPSCO's Fuel Supply Department, which is responsible for administering all coal contracts, verifies that only contract-allowable changes are made to the mine and transportation prices. He explained that after a price adjustment is received, NIPSCO requests supporting evidence in the form of actual invoices and records, as well as published government data, to justify the price adjustment. Mr. Strnatka testified that no price adjustments are made until NIPSCO is satisfied that the charges are in accordance with the contract and are justified by actual costs or changes in cost indices.

Mr. Strnatka said the delivered cost of coal for NIPSCO for the twelve months ending December 31, 2011 was \$51.43 per ton or \$2.570 per million Btu. The delivered coal cost for the reconciliation period (October, November, and December 2011) was \$49.74 per ton or \$2.522 per million Btu. Mr. Strnatka stated NIPSCO made one spot purchase of Illinois Basin high sulfur coal for Units 7 and 8 at its Bailly Generating Station and for Units 17 and 18 at its R.M. Schahfer Generation Station. He testified that the average market spot price of coal (excluding transportation costs) during the reconciliation period was \$13.75 per ton for Powder River Basin ("PRB") coal, \$50.51 per ton for Illinois Basin high sulfur coal, and \$75.90 per ton for Pittsburgh #8 coal.

With respect to the market factors affecting the supply, demand, and cost of coal during the reconciliation period, Mr. Strnatka testified that coal supply during the reconciliation period was impacted largely by the weather, the continuing decrease in the price of natural gas, and the softening of the export markets. He noted the mild weather has decreased electricity demand and placed coal units in economic reserve, causing inventories to move higher; the continuing fall of natural gas prices is causing additional coal to gas switching, thereby creating more coal supply availability on the market and that due to the European debt crisis and the slowing down of the Asian coal markets, it appears less domestic coal is being exported oversees. He stated that consequently, due to the oversupply of coal on the markets, NIPSCO's coal costs during the reconciliation period reflected a slight decrease in price. Mr. Strnatka stated NIPSCO's delivered cost of coal during the reconciliation period decreased compared to the third quarter of 2011 from \$51.76 per ton, or \$2.581 per million Btu, to \$49.74 per ton, or \$2.522 per million Btu. This reduction can be attributed to a decrease in price in an Illinois Basin high sulfur contract coal, using less high-cost Pittsburgh #8 coal, and slightly lower fuel surcharges.

Based on the evidence presented, we find that NIPSCO has adequately explained its coal procurement decision making and we find that its acquisition process is reasonable. Mr. Strnatka's testimony demonstrates NIPSCO has a diverse group of long-term coal contracts with different types of price adjustment mechanisms. Mr. Strnatka explained why NIPSCO and its coal suppliers are reluctant to execute fixed price long-term contracts without some type of market price adjustment mechanism and that maintaining a market price balance is beneficial to both parties. Mr. Strnatka also explained in testimony how NIPSCO makes procurement decisions and the type of market data that NIPSCO tracks and reviews. Based on the evidence presented, we find that NIPSCO has adequately demonstrated that its coal procurement policies are reasonable and prudent.

NIPSCO witness Mr. Roger A. Huhn stated NIPSCO does not purchase natural gas under multiple year contracts because natural gas is not used as a baseload fuel. Therefore, it is purchased on an intermittent basis when one of NIPSCO's gas-fired generation units is more economical to run or needs to run for operational purposes. Mr. Huhn testified NIPSCO has made every reasonable effort to purchase natural gas so as to provide electricity to customers at the lowest reasonable price.

With respect to NIPSCO's efforts to maximize the value of Renewable Energy Credits ("RECs") for its customers, Mr. Williamson stated Indiana does not currently have regulations that guide the certification and accounting for RECs. NIPSCO has thus held the RECs on account with the Midwest Renewable Tracking System due to their relatively low market value and in the event that the State of Indiana were to approve a renewable energy standard. He noted that the Indiana General Assembly recently passed Senate Bill 251, which includes a voluntary renewable energy standard and the Commission conducted a rulemaking process to implement it. He testified that NIPSCO is monitoring the results of that legislation and rulemaking and is making changes in the way RECs are utilized.

Mr. Williamson testified that NIPSCO's treatment of RECs has changed since FAC93. He stated that after a review of Senate Bill 251, NIPSCO believes it will be in the best interests of its customers to sell RECs it acquires. He said NIPSCO will continue to monitor any potential future legislation that would consider NIPSCO's RECs as eligible to meet state renewable energy standards. Appropriate changes will be made as necessary.

The Industrial Group offered as evidence NIPSCO's response to an informal data request, which sought information related to NIPSCO's Electric Hedging Program. The information included the impact of the hedges in terms of gains/(losses) as well as other transactional costs.

Based on the evidence presented, we find that Petitioner has made every reasonable effort to acquire fuel and generate or purchase power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible, as further discussed below. NIPSCO shall continue to include in its quarterly FAC filings updates concerning its utilization of RECs associated with the recovery of wind purchases through the authority granted in Cause No. 43393 and any other future renewable purchases. The Commission also finds NIPSCO shall include evidence regarding its electric hedging costs, gains, and/or losses resulting from the hedging transactions it seeks recovery for through the FAC in its quarterly FAC filings.

8. Midwest ISO Day 2 Energy Costs. NIPSCO included in its forecast the operational changes associated with the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO" or "MISO") Day 2 energy market, in accordance with the Commission's Orders in Cause Nos. 42685, 43426, 43665 and its FAC proceeding from FAC 68. Petitioner included in the FAC factor $3,016,877 as the total "MISO Components of Fuel Cost" for the months of October, November, and December 2011. (Petitioner's Exhibit B, Schedule 5, p. 4, Ln. 19).

9. Interruptible Credits. Mr. Williamson testified the 43969 Order approved Rider 675 – Interruptible Industrial Service, which provides for credits to be paid to certain industrial customers who agree to interrupt their service if certain criteria are met. Ms. Cherven testified that under Cause No. 43969, NIPSCO is authorized to recover 25% of actual interruptible credits paid under Rider 675. Mr. Williamson stated that Rider 675 was only in place from December 27 through December 31, 2011, and during that period, no interruptions were called. According to the evidence, NIPSCO paid a total of $446,402 interruptible credits through Rider 675 during the reconciliation period and NIPSCO is seeking to recover 25% of that total, or $111,600, through the FAC for the billing months of May, June, and July 2012 (Petitioner's Exhibit B, Schedule 8).

10. Estimation of Fuel Cost. Petitioner estimated that its prospective total average fuel costs for the billing months of May, June, and July 2012 will be $40,350,219 (Petitioner's Exhibit B, Revised Schedule 1, Ln. 24) on a monthly basis.

According to Mr. Strnatka, NIPSCO anticipates that its delivered coal cost during the forecast period of April, May, and June 2012 will be approximately $51.43 per ton or $2.58 per million Btu. He explained that a PRB coal solicitation was issued on October 11, 2011 to replace contract coal commencing on April 1, 2012 and NIPSCO is negotiating with suppliers for a multi-year term for high demand, ultra-low-sulfur PRB coal. Mr. Strnatka stated potential increases in price for this type of coal were anticipated due to the implementation of the Cross-State Air Pollution Rule ("CSAPR"), which was scheduled to become effective January 1, 2012. But CSPAR did not go into effect on January 1, 2012 and there is some uncertainty regarding the rule. He said NIPSCO has negotiated a substantial price reduction for Illinois Basin high-sulfur contract coal for 2012 and has negotiated a new multi-year transportation agreement for deliveries of PRB and high-sulfur coal. Overall, NIPSCO is currently projecting a delivered coal cost of $2.58 per million Btu for the forecast period, which could be influenced by the economic dispatch of NIPSCO's coal units and the volatility in the diesel fuel market. Mr. Strnatka testified the average spot market prices for calendar year 2012 (which do not include transportation costs) are currently $14.22 per ton for PRB coal, $48.71 per ton for Illinois Basin coal, and $76.44 per ton for Pittsburgh #8 coal.

Mr. Strnatka explained NIPSCO incorporates all current coal contract prices, estimates of any coal contract price adjustments that might be warranted, transportation contract prices, an assessment of the pricing impact of fuel surcharges on the delivered cost based on current price of crude oil, and an evaluation of the spot market price of coal in developing the estimate for the forecast period. These inputs are provided to NIPSCO's Generation Dispatch & Marketing Group to be used in quarterly updates of PROMOD to develop costs based on demand and projected load forecasts.

Mr. Strnatka discussed in detail the factors he believes will impact the supply, demand, and cost of coal during the forecast period. He testified that overall, NIPSCO is expecting relatively flat coal pricing during the forecast period, and the delivered cost of coal for the forecast period will be relatively flat. The cost of crude presently ranges from $97 to $102 per barrel. Mr. Strnatka testified that if the price of crude remains within this range, NIPSCO's delivered coal cost will be minimally influenced by fuel surcharges paid to the railroads.

In our FAC 90 Order, we ordered NIPSCO to provide detailed testimony and information regarding: (1) average spot market price of coal; (2) factors affecting the supply, demand, and cost of coal; (3) any known factors that significantly impact or affect the supply, demand, and cost of coal during the forecast and reconciliation periods; (4) any known factors that significantly impact the delivered cost of coal during the forecast and reconciliation period; and (5) the process NIPSCO utilizes to procure contracted coal supplies. We find that in this proceeding, NIPSCO provided sufficiently detailed testimony and information to support its forecasted fuel costs as required by our FAC 90 Order. We find that NIPSCO should continue to include in its quarterly FAC filings detailed testimony and information regarding these five factors.

Petitioner previously made the following forecasts of its fuel cost in October, November, and December 2011 and incurred the following actual costs, resulting in a percent error calculated as follows:

Month	Estimated Fuel Cost	Actual Fuel Cost	Over (Under) Estimate
October	$0.031594/kWh	$0.030278/kWh	4.35%
November	$0.031341/kWh	$0.028628/kWh	9.48%
December	$0.031025/kWh	$0.029004/kWh	6.97%
Weighted Average Estimating Error			**6.84%**

(Petitioner's Exhibit B, Schedule 5, pp. 1-3, Lns. 28-29; Petitioner's Exhibit B, Schedule 5, p. 4, Ln. 29).

With respect to fuel costs, OUCC witness Mr. Gregory T. Guerrettaz said he considered a comparison of prior quarter actual and forecast fuel costs and sales figures. Mr. Guerrettaz stated nothing had come to his attention which would indicate that the projections used by NIPSCO for fuel costs and sales of power were unreasonable.

Based on NIPSCO's estimate of its prospective fuel cost and its actual fuel costs for October, November, and December 2011, we find that NIPSCO's estimate of its prospective average fuel cost is reasonable for the billing months of May, June, and July 2012.

11. **Return Earned.** Petitioner's exhibits demonstrate that for the twelve months ending December 31, 2011, Petitioner earned a return of $136,479,509 (Petitioner's Exhibit 2-A, p. 1, Ln. 14b, Col. C), which equates to a 5.04% rate of return. This is less than Petitioner's authorized amount of $188,872,242 (Petitioner's Exhibit 2-A, p. 1, Ln. 14b, Col. B) and 6.98% rate of return (Petitioner's Exhibit 2-B, Ln. 9) approved in Cause No. 43969. Mr. Plantz said actual Environmental Cost Recovery Mechanism operating income is zero (Petitioner's Exhibit 2-A, p. 1, Ln. 14a, Col. B) because there are no realized revenues eligible at December 31, 2011. Therefore, during the twelve months ending December 31, 2011, the Commission finds NIPSCO did not earn a return more than that authorized in its last base rate case, as appropriately adjusted.

12. **Fuel Cost Adjustment Factor.** As discussed in this Order, Petitioner has met the tests of Indiana Code § 8-1-2-42(d) for establishing a revised fuel cost adjustment. Petitioner's evidence presented a variance factor of ($0.001873) per kWh (Petitioner's Exhibit B, Revised Schedule 1, Ln. 27) and a recoverable interruptible factor of $0.000027 to be added to the estimated cost of fuel for the billing months of May, June, and July 2012 in the amount of $0.029748 per kWh (Petitioner's Exhibit B, Revised Schedule 1, Ln. 25). This results in a fuel cost adjustment factor of ($0.000840) per kWh (Petitioner's Exhibit B, Revised Schedule 1, Ln. 32), after subtracting the cost of fuel in NIPSCO's base rates and adjusting for applicable taxes.

For two existing customers billed under Rate Code 647 under contracts approved by the Commission that contain a different base fuel cost and require a special calculation, the fuel cost adjustment factor is $0.005429 per kWh. (Petitioner's Exhibit B, Revised Schedule 1, p. 2 of 2, Ln. 4). OUCC witness Mr. Eckert testified that a residential customer using 1,000 kWh per month will experience an overall decrease of $5.62 on his or her electric bill from the currently approved factor.

13. **<u>OUCC Report</u>.** Mr. Greg Guerrettaz testified: (1) NIPSCO calculated the fuel cost element of the proposed fuel cost adjustment by including additional requirements set forth in various Commission Orders; (2) NIPSCO calculated a variance for the quarter ending December 31, 2011 in conformity with the requirement of Indiana Code § 8-1-2-42; (3) NIPSCO did not have jurisdictional net operating income for the twelve months ending December 31, 2011 greater than granted in its last general rate case; (4) the fuel cost adjustment for the quarter ending December 31, 2011 has been properly applied; and (5) the figures used in the application for change in fuel cost adjustment for the quarter ending December 31, 2011 were supported by NIPSCO's books and records and source documents.

Mr. Michael Eckert testified that NIPSCO's treatment of Ancillary Services Market charges follow the treatment ordered by the Commission in its Phase II Order in Cause No. 43426 dated June 30, 2009. He also testified that pursuant to the Order in Cause No. 43426, NIPSCO is continuing to recover Day Ahead Revenue Sufficiency Guarantee ("RSG") Distribution Amounts and Real Time RSG First Pass Distribution Amounts through the FAC. He noted that NIPSCO's steam generation costs are above average in the State of Indiana and that NIPSCO's actual monthly cost of fuel (mills/kWh) is above the average in the State of Indiana. Mr. Eckert testified that the OUCC recommends the Commission approve the implementation of the NIPSCO's requested FAC factor.

14. **<u>Purchased Power Costs Above Monthly Standard</u>.** Mr. Williamson described the Benchmark that applies to Petitioner's purchased power transactions established in Cause No. 43526. He stated that the daily Benchmark is based upon a generic Gas Turbine ("GT"), using a generic heat rate of 12,500 Btu/kWh times the gas cost determined by using the Platt's Gas Daily Midpoint price for Chicago City Gate, plus a $0.17/mmbtu gas transport charge. Mr. Williamson testified that not all purchased power transactions are subject to the Benchmark—only those that are used to serve FAC load (excluding backup and maintenance contracts) as determined by NIPSCO's RCA system, including bilateral purchases for load and Midwest ISO Day Ahead and Real Time purchases, except wind power purchases which are excluded per Cause No. 43393. He explained that swap transactions and Midwest ISO virtual transactions for generation and load are not subject to the Benchmark. Mr. Williamson testified that NIPSCO did not have any swap or virtual transactions during this FAC period. Mr. Williamson testified that NIPSCO is seeking to recover 1,638.87 MWhs of purchased power in October, 535.55 MWhs of purchased power in November, and 722.56 MWhs of purchased power in December that were in excess of the Purchased Power Daily Benchmark. He said the purchases were made to supply jurisdictional load that offsets available NIPSCO resources which were not dispatched by the Midwest ISO or were otherwise eligible under the procedures outlined in the 43526 Order and are therefore recoverable.

Regarding the purchased power benchmark, OUCC witness Mr. Eckert testified that NIPSCO's testimony and workpapers reflect the Order in Cause No. 43526 regarding purchased power over the benchmark and that he agreed with NIPSCO's calculation of purchased power over the benchmark. Based on the evidence, we find that NIPSCO's identified purchase power costs are properly included in the fuel cost calculation.

15. **<u>Interim Rates</u>.** Because the Commission is unable to determine whether Petitioner will earn an excess return while this Order is in effect, the Commission finds that the rates approved herein should be interim rates, subject to refund.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Petitioner's requested fuel cost adjustment to be applicable to bills rendered in the months of May, June, and July 2012, as set forth in Finding No. 12 above, is hereby approved on an interim basis subject to refund as set out in Finding No. 15 above.

2. Petitioner shall continue to include in its quarterly FAC filings updates concerning its utilization of the RECs associated with the wind purchases being recovered through the FAC as set out in Finding No. 7 above. NIPSCO shall also include in its quarterly FAC filings information as set out in Finding No. 10 above.

3. NIPSCO shall include in its quarterly FAC filings testimony regarding any electric hedging transaction costs, gains and/or losses for which it is seeking recovery through the FAC beginning with FAC95.

4. Petitioner shall file with the Electricity Division of the Commission, prior to placing in effect the fuel cost adjustments herein approved, an amendment to its rate schedule with reasonable reference therein reflecting that such charges are applicable to the rate schedules reflected on the amendment.

5. This Order shall be effective on and after the date of its approval.

<u>ATTERHOLT, BENNETT, LANDIS, MAYS AND ZIEGNER CONCUR:</u>

APPROVED: APR 25 2012

I hereby certify that the above is a true and correct copy of the Order as approved.

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission